SCC-62

Commonwealth of Virginia

STATE CORPORATION COMMISSION

DIVISION OF ENERGY REGULATION

151030117

MEMORANDUM

October 19, 2015

TO: Document Control Center

FROM: Daisy Maldonado, Energy Regulation

RE: PUE-2015-00035 – Virginia Electric and Power Company's - Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq.

Attached are two case comments submitted to the Commission for consideration. Please enter in the case jacket for Case No. PUE-2015-00035. Thank you.

Mr. Thomas Hadwin, et al.

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Clerk's Office
State Corporation Commission
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October 13, 2015

Re: Case Comments for PUE-2015-00035

Dear Clerk's Office,

On October 12, 2015, I attempted multiple times to submit my comments for PUE-2015-00035. I even attempted to submit the comments one page at a time, thinking my document might be too large for the electronic form's text field. No attempts were successful. Today, I contacted Kenneth J. Schrad, Director of the Division of Information Resources, requesting an alternative way to submit my comments.

He replied saying that the best way to submit my comments would be to send them to this address and request that they be considered as timely filed, given my difficulties with your electronic submittal process.

If possible, I would greatly appreciate an e-mail sent to: tzhad13@gmail.com indicating that this document has been received and that it will be considered to be filed on time.

Very truly yours,

Thomas Hadwin

Thomas Hadwin

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Case Comments for PUE-2015-00035
SCC In re: Dominion Virginia Power's Integrated Resource Plan filing

The Integrated Resource Planning process is intended to evaluate the electric utility's forecast of demand for electric generation supply with recommended plans to meet that forecasted demand and assure adequate and sufficient reliability of service. These plans must consider generation from facilities the utility currently operates, intends to construct or purchase; electricity purchases from affiliates or third parties; reductions in load and peak demand growth through cost-effective demand reduction programs in order to propose a portfolio of generation supply resources that will meet the forecasted net demand so that the utility will continue to provide reliable service at reasonable prices over the long term.

The following comments address areas where additional information and additional analyses are needed in order to properly identify the best portfolio of supply and demand side management programs to provide reliable service at reasonable prices over the long term.

Historical Context

The electrical generating industry in the United States began with distributed generation. In 1882, Edison's first generating plant on Pearl Street in New York City served just 59 customers. In early 1883, Edison's Electric Illuminating Company had supplied 334 generators to cotton mills, manufacturing plants, newspapers, grain elevators and theaters. By 1900, about 60 percent of electricity was generated onsite. Samuel Insull, an operator of Edison's company in Chicago, saw the streets filled with wires from his company and its 19 competitors and thought there was a better way. He convinced policy makers and politicians that it would be cheaper for one company to build the distribution system and serve the customers. In return, he accepted regulatory oversight to establish reasonable prices and a fair return to investors. He developed utility holding companies to rapidly consolidate many of the small, local electric companies. By 1930, only 20% of electricity was generated on-site. The era of central station power plants and vertically integrated utilities had begun in earnest. In the early 1930's, Insull's empire collapsed as a result of his overly complex organization of intertwined companies. He was arrested for fraud because of self-dealing within his holding companies which increased customer prices.

Throughout the 1930's investor owned and municipal utilities continued to expand and rural cooperatives also spread out to electrify the countryside. For decades in the middle of the century, regulators had the happy job of deciding how fast rates would decrease. By 1965, the average price of electricity had declined to 1.5 cents per kWh, down from more than 30 cents in 1910.

In the 1970's an abrupt change occurred, to which utilities and regulators have yet to fully adapt. Up until this time, the larger the plants and the more transmission and distribution lines that were built - the lower the costs paid by customers per unit of energy. Electrical demand increased up to 10% a year. In 1973 the first oil embargo occurred, which set back the economy and people became more conscious about using energy.

During this time the federal government was aggressively promoting nuclear energy. Units of this type were built in sizes of at least 1000 MW and they encountered regulatory delays and steep cost overruns. By the early 1980's, some utilities were investing more than their stockholder's equity in new power plants, betting the company that demand would continue to grow at least 7% a year. During this stretch our economy suffered through double digit inflation and high interest rates. Demand leveled off and fell for the first time since the Depression. The generating capacity surplus was as high as 39 percent. Several utilities declared bankruptcy.

The dire straits encountered by utilities under their jurisdiction awoke regulators from their complacency. For decades they had taken their lead from the utilities and things had turned out well. From 1985 to 1991 regulators disapproved $14 billion in nuclear investments, blaming utility executives for poor planning and requiring utility stockholders to accept the loss.

All of these events combined to change the basic economic concept of the utility business. Since its inception the utility industry was a decreasing-unit-cost business. The more utilities built, the bigger the plants, the greater the miles of wires, the cheaper the energy became per kilowatt hour (kWh) for their customers. Suddenly, things had turned upside down. From this time on, whenever a utility built a new plant, a substation, or transmission and distribution lines – no matter how necessary, prices per kilowatt hour increased for their customers. Utilities were now operating an increasing-unit-cost business. Every time they got bigger it gave their customers a greater reason not to do business with them.

Normally, such a shift signals the death or restructuring of a business. It is typically not a good business model to give your customers a reason to purchase less from you. However, the electrical utility business is not like others. Not because it is regulated. There have been other regulated industries: airlines, telecommunications, etc. It is because electricity is an essential commodity. It is fundamental to our way of life. When the power goes off, the routines of our everyday life come to a halt. We are willing to pay whatever it costs to have it (economists call this price response – inelastic). Besides, customers don't really have a choice. With their monopoly status, utilities have been somewhat immune from the price signals that they have been sending to customers.

The shifts in the utility industry caused a regulatory and legislative response. In 1978, Congress passed the Public Utilities Regulatory Policy Act (PURPA). This act prohibited utilities from obstructing onsite power generation and required that they purchase generation from Independent Power Producers (IPP's) under certain circumstances. In its original form, PURPA supported decentralized generation by applying only to plants under 80 MW. After intensive lobbying by major interests, larger producers could qualify under the regulations. Congress also deregulated the wholesale electricity market. By 1994, IPP's accounted for almost three-quarters of new capacity.

While allowing independent producers access to the wholesale market, Congress also gave them access to the high-voltage transmission system on an equal standing with existing utilities. Electricity does not follow a specific path like cars on a highway. It follows the path of least resistance. This surge of new traffic on their transmission systems caused congestion and imposed real costs on utilities.

For decades utilities cooperated with their neighbors to share generation resources and to plan transmission projects to facilitate that sharing and ensure the reliability of their systems. The influx of independents caused the formalization of various price-based markets for the exchange of wholesale generation (the Independent System Operators – ISO's). To facilitate this energy exchange, interstate transmission networks were required, operated by Regional Transmission Operators (RTO's). In our region both of these functions are performed by PJM. The Federal Energy Regulatory Commission (FERC) has supplanted state regulators for the authorization of transmission lines used in this interstate network and also grants utilities a higher rate of return (13.5%) than is typically allowed by state regulatory commissions.

Members of PJM (such as Dominion) must provide sufficient generation resources, plus appropriate reserves, to meet their share of the PJM peak. PJM has final authority over the planning and operation of generation and transmission resources within their jurisdiction. FERC has also required regulated utilities that are members of ISO's to separate the entries for generation, transmission, and distribution/retail operations in their bookkeeping. In states that have not fully deregulated, these requirements cause vertically integrated utilities to operate as de facto independent generation companies. As a result, Dominion Virginia Power's generation planning is geared to meet the needs of the PJM market.

Recent innovations are starting to give customers more of a choice about how much energy they use and from where it is provided. They can choose to avail themselves of utility provided DSM programs, local contractors, or offerings from Energy Service Companies (ESCO's) to reduce their energy use. Customers also have greater and increasingly less expensive choices for self generation. Price is often the overriding factor, but environmental concerns and desire for greater self-reliance also enter the picture. For the first time, these new choices are providing customers real options as to how they respond to utility pricing signals. These customer actions have an influence on both supply and demand. Only the utility provided programs and resources are considered in this plan. The Virginia State Corporation Commission, through its policies and rate structures, has great influence on the programs for load reduction and the mix of generation supply that Dominion chooses to meet its obligation to provide reliable power at a reasonable price.

The comments which follow are intended to identify additional ways or suggest additional analyses that could lead to better, less expensive ways of achieving the same end.

Comments on Dominion Virginia Power's Integrated Resource Plan

Chapter 2 – Load Forecast

The load forecast is the foundation for the IRP planning process. It becomes the target by which all subsequent choices are measured. For this reason, it is essential that the assumptions underlying the forecast are examined.

There is no question about the adequacy of the models used or the skill of those applying them. However, utilities have a history of overestimating demand. This is understandable. They take their responsibility for providing adequate, reliable service very seriously. It is better to err on the side of having a bit too much capacity than to risk having too little. As such, utility outlooks tend to assume the future will be very similar to the past. If non-standard scenarios have been modeled, they are not described in the IRP. There are a number of possible issues which could have a considerable effect on lowering load growth that do not appear to be considered in the 2015 plan.

Load Growth is Now Decoupled from GDP Growth

For the past 7 to 8 years, electricity use has been flat or declining in the U.S., although the economy has increased about 8 percent.[1] New innovations are coming to market which allow us to produce more economic activity while using less energy. The energy intensity (the amount of energy used per unit of state GDP) in Virginia is about 50% more than the energy required to produce a unit of GDP in California.[2] With reasonable energy efficiency, there is plenty of room to expand our state economy without increasing load.

Even utility executives realize that the historical linkage between energy use and the economy has changed. Duke Energy's CEO Jim Rogers noted, "we are not going to reach [forecasted] 2019 [load] levels until 2030 despite an economic rebound since 2008. In past decades, for every 1 percent growth in gross domestic product, there was as much as 5 percent growth in demand for electricity. But those days are gone." He also said that "We are on the way to seeing a decoupling of the growth of demand for electricity with the growth in GDP. That will have a profound implication for how we think about our business."[3]

American Electric Power (parent company of Appalachian Power) Chief Financial Officer and Executive Vice President Brian Tierney told the September 2012 Bank of America/Merrill Lynch Power and Gas Leaders Conference: "On the industrial side, a lot of our customers have already made changes to their demand consumption and are being as energy efficient as possible, but we are starting to see some of those trends work their way into the commercial side of the business and even into people's homes. It is not just behavioral modification; we think there are some structural changes."[4]

Customers have More Choices to Improve Energy Efficiency

Smart thermostats, more efficient appliances, aggregator programs and other means are becoming readily available for residential customers to reduce their loads. These choices are outside of the DSM programs described in this plan and therefore are not factored into the net reductions in load growth. Many options are just gaining the attention of consumers and will

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[1] U.S. Electricity Demand Flat Since 2007, Katherine Tweed Posted 6 Feb 2015, http://spectrum.ieee.org/energywise/energy/environment/us-electricity-demand-flat-since-2007

[2] Energy Self-reliant States, 2nd Edition, Institute for Local Self-Reliance, October 14, 2012, https://ilsr.org/energy-self-reliant-states-2nd-edition-0/

[3] *Duke's Rogers call for utility, regulatory business model 'rethink'*, SNL Financial, January 30, 2013.

[4] *Utility executives agree 'fundamental changes' dampen future demand growth,* SNL Financial, September 21, 2012.

ramp up rapidly over the next 5-10 years. Given that they are recent arrivals, their effect is not reflected in the past history used for the models.

Independent energy service companies are approaching commercial and industrial clients offering no upfront payments with immediate savings and investment payback periods of less than 10 years (often just a few years). Deeper retrofits can offer even greater savings. Dominion could choose to play a major role in this market, but in any case it will reduce load below projections.

Military Bases

Virginia has a large presence of federal installations, especially military bases. The Department of Defense has embarked on a worldwide program of reducing energy use and improving reliability and energy security, using microgrids and other means. Dominion should expect to see significant reductions in loads from military installations within its territory over the next 15 years.

Savings from the retrofits at the Naval Air Station Oceana outside of Virginia Beach are a good example. Using an energy savings performance contract (ESPC), the project, expected to be completed in 2017, is projected to reduce energy use by over 40% across more than 100 buildings and save the naval base over $6 million per year in energy costs.[5] Dominion should forecast similar reductions in load from other bases in its service territory,

Customer Sited Distributed Energy Resources

The tech companies running data centers in Northern Virginia are interested (and also pressured by shareholders) to provide more of their energy use from renewable sources. The 80 MW solar facility that Amazon intends to develop in Accomack County, Virginia is an example of that trend.[6] Other companies are looking to reduce costs and appear forward thinking and will be developing their own sources of generation. Policies to discourage this will only prompt innovative companies to locate elsewhere. North Carolina is certainly positioning itself to attract those types of businesses, "to create high paying jobs while making our state the emerging clean tech hub of the eastern U.S.," according to Dale Freudenberger, CEO of FLS Energy.[7]

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[5] How the U.S. Navy Plans to Save 6 Million Per Year at One Air Station. Rocky Mountain Institute, Aug 11, 2015, http://blog.rmi.org/blog_2015_08_11_us_navy_plans_to_save_6_million_per_year_at_one_air_station

[6] Amazon Moving Forward with 80 MW Virginia Solar Farm, September 29, 2015, http://www.seia.org/news/amazon-moving-forward-80-mw-virginia-solar-farm

[7] North Carolina Realizing its Solar Potential, Jaclyn Brandt, August 11, 2015, http://www.fierceenergy.com/story/north-carolina-realizing-its-solar-potential/2015-08-11

While a portion of this distributed generation will end up as part of Dominion's supply, it will offset some of the load that Dominion had anticipated supplying in the load forecast. These new DER's should not be viewed as a threat, but as an opportunity. They can reduce load, which cuts costs both for the utility and customers. New policies can be developed to protect Dominion's profits as revenues decline.

Expected price declines over the next 5-10 years will increase customer adoption of residential solar. While also reducing load, this should be considered a resource for CPP purposes.

Effects of Fuel Price Increases

In the IRP, Dominion is projecting the high fuel cost case for natural gas to be 10% higher than the base case over the life of the plant. When Australia elected to use their natural gas for non-traditional uses such as burning it in power plants and exporting LNG, their prices for domestic natural gas increased 300 – 400%. Factories closed or switched back to coal. Homeowner's utility rates soared. We are on that same path in the U.S. and Dominion is speeding up the use of affordable natural gas with their Cove Point LNG facility. Independent experts predict that the output of affordable natural gas ($4 mcf) from the Marcellus will peak about 2018 – 2020. After that, more gas will be available but at much higher prices. Improved technology always offers hope, but the productivity gains from technology peaked in the second half of last year and are now declining in the Marcellus. More than 1000 new wells must be drilled each year just to maintain production levels. Energy prices for Natural Gas Combined Cycle units are approximately 50% capital costs and 50% fuel costs. A significant increase in natural gas prices in the years 2020 – 2030 would pass through to ratepayers. With the recent and planned increase of combined cycle units in Dominion's generation portfolio, plus co-fired units and gas-fired peaking units, increased gas prices would increase customer bills and could have a marked effect on load growth. A more in-depth discussion and supporting references will be provided in the section on fuel costs.

Economic Uncertainty

Utilities have experienced declines in load growth during periods of economic uncertainty. Lowered or negative load growth resulted from the oil embargo in the 70's, the recent Great Recession and the downward economic cycles in between. There was also greater customer acceptance of energy efficiency measures as economic growth resumed. Utility load forecasters are not economic prognosticators (and even those that are don't often get it right). However, since more than seven years have elapsed since the last downturn, there is a measurable chance of another down cycle, perhaps a significant one, before the end of the planning period fifteen years from now.

Unlikely, but plausible scenarios should be modeled to add to the Commission's considerations. The oil and gas drilling industry has been almost entirely responsible for the new job creation in the U.S. since 2008. They are also highly leveraged with over $700 billion in debt (larger than the toxic assets in the housing bubble). Low commodity prices are causing developers to continue to drill, even at a loss, in order to generate cash to service the debt. Continued production has added to the surplus and driven prices lower. Several of the less efficient shale oil producers have already declared bankruptcy. Drilling rig counts have dropped substantially, even in the Marcellus. If this huge debt overhang cannot be managed, we are in for a repeat of 2008, only on a potentially larger scale.

U.S. and world debt continues to expand. There are currency concerns and the U.S. influence in the world economy is giving way to much more populated regions. Effective decision makers evaluate a variety of possibilities and develop contingency plans. Scenarios with lower load growth, much higher fuel costs, greater DER penetration and some significant economic upsets should be modeled to observe the results, especially in the 5 – 10 year range. Some consideration might be given to postponing the projected start date of the Greensville combined cycle plant by a year or two to gain greater clarity before a substantial investment is made in an asset that might not have a market. Scenarios at the end of the planning period could include the addition of greater CPP requirements or the addition of a carbon price. The Commission needs more information to inform its decisions.

We are in a time of great transition in the energy industry. Decisions regarding projects that have a 40 – 60 year useful life can have significant consequences. Flexibility and rapid response should be built into the long-term generation plan. Neither the SCC, nor Dominion Virginia Power wants to face the issue of substantial stranded costs. This modeling effort should be a collaborative effort with Dominion or subcontracted to an independent contractor.

Chapter 4 – Planning Assumptions

Renewable Energy

Transitioning to a more modern energy system is a challenge for regulators and utilities. Traditionally, if a utility did not own an asset it was not considered a "resource". It appears that Dominion is continuing that tradition in the current Integrated Resource Plan. The energy market is shifting, with or without the permission or participation of regulators and utilities. If the contributions of customer sited renewable distributed energy resources are not considered on the supply side and the energy efficiencies provided by ESCO's and other independents are not included in the load reduction calculations - a very skewed forecast of the future load will be produced.

These non-utility contributions are most certainly resources. Not only for load reduction and supply, but for PJM DSM markets and CPP credits. Policies and appropriate rates should be developed for Dominion to encourage third-party participation in creating these resources, while protecting their profits as revenues decline. This is a challenge that is under discussion in many states. Numerous regulatory jurisdictions have decoupled rates to reduce the incentive for utilities to expand generating capacity in order to create the revenues needed to continue to attract investors. Without new policies, utilities typically oppose these new developments (they want to own it all), or they underestimate how quickly it could grow if they were neutral or supportive of it. For example, Duke Energy has simultaneously proposed large-scale solar investments while trying to suppress competition from smaller producers. The utility has proposed owning or purchasing power from over 500 MW of solar power plants – earning a 10% rate of return on the plants it owns – while trying to reduce eligibility for third-party solar projects. Shawn LeMond, a former Republican North Carolina legislator says it's an anti-competitive move. "Duke is putting $500 million into solar," LeMond said. "But what they are doing at the utility commission is stopping independent [developers] from building five times that. The market would build a lot more solar, but Duke is fighting it."[8]

Decoupling rates has not completely addressed this issue. It is noted that this docket is not a rate-making proceeding, but it is essential to recognize that by ignoring growing customer activities within the Dominion Virginia Power service territory that affect both load and supply – we will not achieve an optimal decision about the timing, amount, and type of units to comprise the future generation portfolio. There are clear benefits in terms of lower customer bills, reduced environmental effects, and overall grid reliability from energy efficiency and renewable distributed generation (whether customer, third-party, or utility owned) that are not being addressed in this plan. That omission should be remedied.

Carbon Price Assumptions

Dominion is using a shadow price of $20 - $25 per ton to reflect the marginal cost of complying with the emissions cap specified in the proposed Clean Power Plan (CPP). Their calculations are based on conditions specific to Virginia and could prove accurate. However, utilities throughout the U.S. have been using a shadow price of $50 per ton which is more than double what Dominion has assumed for their long range planning purposes. Since this is such a large discrepancy, perhaps a model run should be done to see what changes result from using this more widely accepted figure.

Natural Gas Price Assumptions

Utility executives are well aware that natural gas has much greater price volatility than other traditional fuels used for electric generation such as coal and nuclear power. For a time, use of natural gas to fuel new generating facilities was outlawed because of resource shortages. With environmental concerns and economic issues relating to coal plants, most of the large new generating facilities being planned for the next 10-15 years will use natural gas. We should be aware of the consequences of relying on a single fuel for much of the generation proposed in this plan.

There is a good deal of confusion about the amount of natural gas in the U.S. Unfortunately, early published numbers regarding shale gas identified "resources" for various shale plays. The numbers were so large that it caused people to exaggerate and say that we now had a "100 year supply" of natural gas. In the oil & gas industry, **resource** means the amount of gas or oil that

[8] Trabish, Herman. Duke Buying $500M of North Carolina Solar to Mixed Reviews. (Greentech Media, 9/18/14), http://bit.ly/1rTtelD.

remains underground, and **reserve** means what could be produced from the resource. Only a portion of the resources can be recovered technically. Only a portion of the technically recoverable resources can be produced economically. Only a portion of the economically producible resources can be converted into supply. This economically producible supply is called a **reserve**. A reserve is only truly meaningful when you identify the price that is used to establish its size. The volume of the reserve for gas selling at $4 per thousand cubic feet (mcf) is smaller than the reserve for gas at $10-$12 mcf. If you want more gas you will have to pay a higher price for it. An industry insider has noted, "We can have cheap natural gas or we can have plentiful natural gas, but we're not going to have cheap, plentiful natural gas."

In the 1990's natural gas was cheap - $2 mcf. In the easy money days of the early 2000's the economy picked up; demand exceeded supply; and we started to import natural gas which caused prices to rise to over $13.50 mcf in 2008. Drillers rushed in to the known but undeveloped shale gas formations in hopes of substantial gains. They soon discovered that the shale gas wells declined significantly within the first few years of production.[9] Their experience with drilling for conventional gas was that wells would decline slowly over several decades.

Developers had big loans to pay for leases and drilling rigs but received much lower than expected revenues because of the rapid well declines. They decided to keep drilling (even at a loss) to generate the cash to pay the loans. All of the drilling greatly increased supply, the economy crashed after the housing crisis, demand sank and prices began to fall.

Wall Street investment bankers stepped in to seize a profit opportunity. They repackaged the drilling leases in much the same way they had repackaged mortgages and resold them for a profit. They resold the leases using drilling history from early profitable wells and said that the parcel was "proved up" and thus a "safe investment".[10] As worldwide oil prices peaked in 2011, foreign investors rushed in to buy up these leases thinking they were gaining access to a long-term supply of cheap gas.

The second group of developers repeated the experience of the first. Production rapidly declined and too few wells were actually profitable. They got on the same treadmill and kept drilling wells to generate cash to meet their debt service. All of these wells added to overall supply and the surplus drove prices lower still. By January, 2012, prices had plunged to under $3 mcf – far

[9] Rafael Sandrea, "Evaluating Production Potential of Mature U.S. Oil, Gas, Shale Plays", IPC Petroleum Consultants, 12/03/2012 http://www.ogj.com/articles/print/vol-110/issue-12/explorationdevelopment/evaluating-production-potential-of-mature-us-oil.html

[10] Joe Carroll and Jim Polson, "U.S. Shale Bubble Inflates After Near-Record Prices for Untested Fields", *Bloomberg*, January 2012
http://www.bloomberg.com/news/2012-01-09/shale-bubble-inflates-on-nearrecord-prices-for-untested-fields.html

too low for operators whose breakeven costs were about $4 – 6 mcf. Many took huge write-downs of their shale gas investments.[11]

Investment bankers made more money doing mergers and acquisitions with the now ailing companies, to which they had recently sold leases labeled as "safe investments".[12] Wall Street investment banks continued to promote shale gas plays, despite the experience of developers.

Drillers became very efficient at working the "sweet spots". Technology advanced so more wells could be drilled from a single drilling rig, making drilling more productive and less expensive.

Although U.S. natural gas supply expanded by 5.2 billion cubic feet per day (Bcf/d) in 2014; demand grew by only 0.9 Bcf/d. Normally, production would be curtailed until supply more closely matched demand and the price increased. But the need for cash flow prevailed and more wells were drilled. But low prices have taken a toll on rig count. U.S. natural gas drilling rigs have fallen by nearly a third, from 320 to 222. U.S. oil drilling rigs have been harder hit, falling by over half, from 1,536 to 642. (This is important because associated gas from crude oil wells accounts for about 10% of natural gas production.) [13]

Natural gas prices were $2.65 mcf in June 2015; 40% lower than a year earlier largely due to the excess production from Marcellus. The lack of connections from the Marcellus to existing pipelines kept the gas from easily getting to major markets. This "stranded" gas could sell only at a significantly lower level than the national price. Pipelines are being developed to connect Marcellus production to existing pipelines, so this situation is expected to be remedied by 2017.

The Marcellus is now the largest natural gas production area in the U.S. and is being counted on to supply abundant cheap gas for decades to come. For some time, it has been difficult to obtain current accurate information about the field's production. West Virginia provides data for one full year at a time. Pennsylvania is now a bit better, releasing data for six-month intervals. Data for 2014 are now available which provide a good measure of what is happening since Pennsylvania wells are 85% - 90% of the Marcellus production. David Hughes, a geoscientist and expert regarding unconventional natural gas potential for the Geological Survey of Canada and now the Post Carbon Institute in the U.S., has developed an in-depth assessment of all

[11] OGJ Editors, "BHP Billiton writes down Fayetteville shale values", *Oil and Gas Journal*, August 2012, http://www.ogj.com/articles/2012/08/bhp-billiton-writes-down-us-shale-values.html

[12] KPMG, "Shale Gas M&A Activity in US, Argentina and China on the Rise: KPMG Report", June 2012, http://www.kpmg.com/global/en/issuesandinsights/articlespublications/press-releases/pages/shale-gas-maactivity-in-us-argentina-and-china.aspx

[13] Oh US gas demand, where art thou? Peak Oil News, June 11, 2015 http://peakoil.com/consumption/oh-us-gas-demand-where-art-thou

drilling and production data from the major shale plays. Some of his findings are summarized below: [14]

- Field decline averages 32% per year in the Marcellus. Over 1000 new wells are required each year just to maintain production levels.

- Three of the 70 counties account for nearly half of the play's production, five counties account for two-thirds, and 12 counties account for 90%.

- Drilling is concentrated in the top counties which have the greatest economic payback; **<u>the cheapest gas is being produced now, leaving the expensive gas for later.</u>**

- Average well productivity increased between early 2012 and early 2014 as operators applied better technology and focused on "sweet spots".

- The increase in well productivity over time peaked in 2014 and has fallen in the last half of 2014.

- Better technology is no longer increasing average well productivity in the top counties. This is a result of either drilling in poorer locations or from well interference – where one well cannibalizes another well's gas.

- Geology appears to be trumping technology in Susquehanna County, which is the most productive area. Well density was 1.48 wells per square mile in mid-2014 with the assumption that 4.3 wells per square mile could be drilled; this may be overly optimistic.

- This declining well productivity is significant, yet expected, as top counties become saturated with wells, and will degrade the economics which have allowed operators to sell into Appalachian gas hubs (e.g. Dominion South) at a significant discount to Henry hub gas prices.

- There is a backlog of wells which have not yet been hooked to pipelines (often waiting for a higher gas price). This cushion can maintain or increase Marcellus production as they are connected even if rig counts continue to fall.

- Current drilling rates are sufficient to keep Marcellus production growing until its **<u>projected peak in 2018</u>**, **<u>followed by a terminal decline</u>** (which assumes gradual increases in price; sudden major increases in price could temporarily check this decline if reflected in significantly increased drilling rates).

- **<u>As for the massive investments in infrastructure on the assumption of cheap and abundant gas for the foreseeable future</u>** – *CAVEAT EMPTOR.*

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[14] Marcellus Production Outlook, David Hughes April 28, 2015
http://www.postcarbon.org/marcellus-production-outlook/ http://www.postcarbon.org/publications/drillingdeeper/

Energy industry executives, politicians and policymakers have made policy and business decisions based on the forecasts from the Department of Energy's Energy Information Administration (EIA). At the beginning of shale development there was a general assumption that we will have decades of affordable, plentiful natural gas. Current experience doesn't match the forecasts. Why does the popular perception differ from what the experts are finding?

In order to have an accurate, unbiased assessment of shale gas potential, a team of a dozen geoscientists, petroleum engineers and economists at the University of Texas at Austin spent more than three years on a systematic study of the major shale plays. According to an article in Nature, the team received a $1.5 million grant from the Sloan Foundation to accomplish the research.[15] Ruud Weijermars, a geoscientist at Texas A&M University notes the work is the "most authoritative" in this area so far.

The University of Texas team assumed natural gas prices would follow the scenario that the EIA used in its 2014 annual report (a price level of about $4 mcf). The Texas team forecasts that production from the big four plays would peak in 2020, and decline from then on. By 2030, these plays would be producing only about half as much as in the EIA's reference case. Even the agency's most conservative scenarios seem to be higher than the Texas team's forecasts.

The main difference between the Texas and EIA forecasts relates to how fine-grained each assessment is. The EIA breaks up each shale play by county, calculating an average well productivity for that entire area. But counties often cover hundreds of square miles, large enough to hold thousands of shale gas wells. The Texas team, by contrast, splits each play into blocks of one square mile, a much finer resolution than the EIA's.

Resolution matters because each play has sweet spots that yield a lot of gas, and large areas where wells are less productive. Companies try to target the sweet spots first, so wells drilled in the future may be less productive than current ones. The EIA's model so far has assumed that future wells will be at least as productive as past wells in the same county. But this approach, the Texas team argues, "leads to results that are way too optimistic".

The high resolution of the Texas studies allows their model to distinguish the sweet spots from the marginal areas. As a result, says study co-leader Scott Tinker, a geoscientist at the University of Texas at Austin, "we've been able to say, better than in the past, what a future well would look like". After reviewing the University of Texas study, the EIA has changed course and predicted that contributions to domestic natural gas production from shale gas sources will peak around 2020 at their Reference Case price levels.

Members of the Texas team are still debating the implications of their own study. Tinker considers that the team's estimates are "conservative", so actual production could turn out to be higher. The big four shale-gas plays, he says, will yield "a pretty robust contribution of natural gas to the country for the next few decades. It's bought quite a bit of time."

[15] Natural Gas: The Fracking Fallacy, Mason Inman, *Nature,* December 3, 2014 http://www.nature.com/news/natural-gas-the-fracking-fallacy-1.16430

Dr. Patzek, head of the University of Texas at Austin's Department of Petroleum and Geosystems Engineering, and a member of the University of Texas research team, argues that actual production could come out lower than the team's forecasts. He talks about it hitting a peak in the next decade or so — and after that, "there's going to be a pretty fast decline on the other side", he says. "That's when there's going to be a rude awakening for the United States." He expects that gas prices will rise steeply, and that the nation may end up building more gas-powered industrial plants and vehicles than it will be able to afford to run. "The bottom line is, no matter what happens and how it unfolds," he says, "it cannot be good for the US economy."

Australia's experience might be a cautionary tale for the U.S. When that country began to use its plentiful natural gas for new uses such as burning it in power plants and the export of LNG, domestic prices tripled, with prices still rising. An article in the Oil & Gas Journal notes, "Australian manufacturers are closing their doors and power companies and industries are taking action to switch from natural gas to coal." As the cost of home heating and cooling has soared, "Domestic consumers are suffering because Australian public policymakers failed to take care of the people who have entrusted them to represent their interests. This has turned Australia's natural gas from a strategic asset to a liability for domestic consumers."

The Australian government expected that supply would keep pace with the non-traditional demands such as exports. The same assumption underpins U.S. policy makers push for more gas-fired power plants and LNG exports. The U.S. Department of Energy's own studies predict that increased demand for natural gas for LNG exports would "reduce wages and disposable income, increase energy prices, (and) curb investment in the U.S. economy (less investment in manufacturing)." The energy companies would be the ones to benefit from such a plan, "while the vast majority of the people in the country will lose economically".

Increased utility prices might not be the only effect of rising natural gas prices in Dominion's service territory. Affordable gas and natural gas liquids give an advantage to U.S. industries over their overseas competitors. Jobs are just beginning to move back to the U.S. for industries which rely on these feedstocks. These U.S. manufacturers think the rush to burn up our affordable natural gas in electric power plants or sending it overseas is a bad idea. Increased natural gas prices could cut back manufacturing in Virginia and reduce the projected load.

Paul Cicio, president of the Industrial Energy Consumers of America (IECA), a nonpartisan association of leading manufacturing companies with $1 trillion in annual sales and more than 2,900 facilities nationwide, believes that exporting LNG could threaten Virginia's 231,073 manufacturing jobs and jobs throughout the nation. The concern is that high energy prices could stop the Virginia manufacturing renaissance that has created so many new jobs. Mr. Cicio says that our rush to export our secure supply of affordable natural gas "has unsettling consequences for manufacturing industries that depend upon affordable natural gas and power – but in fact, it will also substantially raise costs for all consumers and have detrimental effects to the economy long-term." [16]

[16] http://www.roanoke.com/opinion/commentary/cicio-gas-exports-threaten-virginia-manufacturing-jobs/article_2d4339a4-cbfb-11e3-80e5-001a4bcf6878.html

There is no definitive answer yet. Technological advances and market movements have a way of surprising us. However, with the entire U.S. utility industry moving towards much higher reliance on natural gas, it is worth a detailed look at the consequences of a significant price increase for natural gas in the 2020 to 2030 time frame. A high gas price case of just 10% higher than the base case, is not sufficient to understand the consequences of a doubling or tripling of natural gas prices over a five year period in the early 2020's. We experienced $13.50 mcf gas just seven years ago. At that time we were not exporting it or burning it in our baseload power plants.

This evaluation should also be part of the consideration for the approval of the Greensville combined cycle plant. If scenarios with higher fuel prices or lower loads reduce the long term value of this unit, perhaps the scheduled operation date could be postponed by a year or two until the trends become more apparent. Aggressive energy efficiency programs (see later sections) or more short lead time solar units could be used to fill the gap if reserve requirements were truly threatened by this delay. The consequences of approving a plant with a 40-60 year life that could prove to have a limited market are substantial. In the early 1980's, regulators disapproved of $14 billion in utility investments in nuclear plants that were no longer justified as load growth declined. This failure of foresight was expensive to utility shareholders and to customers.

Atlantic Coast Pipeline

Expansions of existing pipelines will provide more than twice the additional capacity projected for the Atlantic Coast pipeline. A pipeline extension (Atlantic Sunrise) from the Marcellus to the Transco pipeline as it passes through Pennsylvania will add 1.8-2.0 billion cubic feet per day (Bcf/d) of additional capacity to that pipeline system. Both the Brunswick plant and the Greensville plant will connect to the Transco pipeline. The Transco pipeline is designed to accommodate a flow of gas both from the Marcellus and the Gulf Coast to ensure the highest levels of service reliability. The WB Xpress development of the Columbia Gas pipeline requires only 26 miles of replacement pipeline and just 2.5 miles of new construction to add 1.3 Bcf/d of capacity. The Columbia Gas pipeline enters the state from West Virginia and passes through northern and central Virginia and connects to the Virginia Natural Gas pipeline serving the Hampton/Norfolk area.

Together, these expansions will provide over twice the capacity provided by the Atlantic Coast Pipeline (ACP) and serve exactly the same areas projected for the ACP, including North Carolina. A study by the Department of Energy, "Natural Gas Infrastructure", addressed the options for providing more gas to the southeast.[17] The DOE report states, "Even with the significance of the Marcellus, projected natural gas production and demand are geographically diverse, so the need for additional interstate natural gas pipeline infrastructure is lower than

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[17] The U.S. Department of Energy, "Natural Gas Infrastructure"
http://energy.gov/sites/prod/files/2015/02/f19/DOE%20Report%20Natural%20Gas%20Infrastructure%20V_02-02.pdf

would be expected if the increased production or demand were concentrated in a particular region." Furthermore, pipelines built since 2007 to accommodate " increases in shale gas production are projected to reduce the need for future pipeline infrastructure." The Department of Energy explains how existing pipelines can be utilized to serve higher demand in Virginia: "Flow reversal [of existing pipelines] is also projected southward out of the Marcellus to serve markets in the Southeast. Pipelines that currently bring natural gas from the Gulf region to the north are projected to reverse flow so that Marcellus production can serve the Virginia and Carolinas markets".

The report goes on to say that even if more coal-fired and nuclear plants are retired than expected, there is sufficient capacity in the existing system to handle the demand. The DOE report states, "Projected pipeline utilization for the top 200 pipeline segments by projected flow volume in the model in 2030 rises to 60% in the Intermediate Demand Case and 61% in the High Demand Case, compared to 57% in the Reference Case."

The Atlantic Coast Pipeline might make business sense for the Dominion and Duke holding companies. They would prefer to pay themselves rather than someone else to transport the gas. However, the Atlantic Coast Pipeline provides no benefits to Dominion Virginia Power customers. It is possible that gas transport using existing pipelines might be less expensive for DVP since the expansion of the existing pipelines is projected to cost far less than the $5 billion needed for the Atlantic Coast Pipeline. Dominion could continue its firm commitment for gas supply through the Transco pipeline for the life of the Southside plants.

There should be no consideration of an adverse effect on costs for Dominion Virginia Power if the application for the Atlantic Coast Pipeline is denied.

<u>Chapter 5 – Future Resources</u>

Dispatchable Resources

Consideration should be given to microturbine Combined Heat and Power (CHP) units, either Dominion owned or developed and aggregated by others. With the long term prospects of higher natural gas prices, these units extract 80-85% of the energy content of natural gas compared to the 50% or lower efficiencies in other gas-fired units. The added efficiency comes from the use of waste heat to provide heating and cooling services in addition to generating electricity. They are also distributed energy resources which reduce congestion and improve reliability of the system. They can be incorporated in microgrids for campuses, or areas of essential service. The rapidly responsive units can be managed from Dominion's control center to match variations in distributed solar installations and serve a variety of grid support functions. The thermal component can be stored, so heating and cooling peaks can be further reduced. The last half century history of utilities has been one of central station power. Recently, progress in communications, digital technology and miniaturization has presented us with new options. There is increasing awareness of the benefits of battery storage combined with distributed renewable generation. Similar attention should be given to this option for dispatchable distributed generation, especially because it is an excellent complement to solar generation. Investments in on-site combined heat and power generation are on the rise. An Executive Order issued in 2012 established a new national goal of 40 GW of new CHP capacity by 2020—a 50-percent increase from today.

The large combined cycle plants going into operation between 2014 and 2019 are much more efficient than simple cycle combustion turbines (peakers). However, combined cycle plants are not able to ramp up their output nearly as quickly, a crucial advantage to match the variability of wind and solar power. Simple combustion turbines can ramp their output up and down by 22% of their maximum capacity per minute. Combined cycle plants are more similar in response to coal plants and can only ramp their output by 2.5% per minute.[18]

Nuclear

Nuclear is attractive as a non-carbon source of generation. However, despite having the highest subsidies of any type of generation, nuclear is 4-5 times more expensive than an equivalent sized combined cycle plant. The current experience with nuclear in the U.S. is not encouraging. The first nuclear unit scheduled to come on line in this century, TVA Watts Bar Unit 2, began construction more than 40 years ago. It was halted, 80% complete, in 1998 for lack of demand. Construction recommenced in 2007 and initial operation is expected in 2016. The 1150 MW plant is expected to cost $4.5 billion. Other new nuclear plants proposed in the U.S. are either still on the drawing board or construction is far behind schedule and drastically over budget. A new nuclear plant in Scandinavia, being built by a highly experienced French nuclear contractor, is 24 months behind schedule and 100% over budget after just 28 months of construction.

In 2012, Jeffrey Immelt, CEO of General Electric, the company designing the GE-Hitachi reactor that is being considered for North Anna Unit 3, told the London Financial Times, "It's just really hard to justify nuclear, really hard . . . at some point, really, economics rule". He went on to say that natural gas power plants and renewable energy such as wind and solar will be the best investments over the foreseeable future.[19]

Fuel cost, an early advantage of nuclear plants, is rising because of increasing reliance on imported materials. Dominion Resources closed its Kewaunee nuclear plant in Wisconsin in 2013, because it was unable to make money in the MISO market. The costs for alternative methods of generation are going down, while costs for future nuclear units keep going up. Given that a new nuclear plant could be not built on schedule at anywhere near a competitive price for the PJM market, Dominion should halt any further consideration of North Anna Unit 3, or at least be prohibited from charging any more expenses related to that unit to ratepayers. No kilowatt-hours of energy will result from that investment.

[18] Cost and Performance Data for Power Technologies. (Black & Veatch for the National Renewable Energy Laboratory, February 2012). http://bit.ly/14ShuFn.

[19] " Immelt can't justify nuclear power", Larry Rulison, Times Union, July 30, 2012, http://www.timesunion.com/business/article/Immelt-can-t-justify-nuclear-power-3747910.php

Non-Dispatchable Resources

Onshore Wind

The IRP is correct in noting that the Southeastern United States is not a high wind resource area. Our best areas are on mountain ridge tops or along the shoreline. Visual concerns and transmission issues make site selection difficult. Exploration of suitable prospects should continue.

Offshore Wind

Offshore winds provide a much more abundant energy resource, but one that is challenging and expensive to realize. An entire infrastructure for offshore platforms and underwater transmission must be established along the east coast before this option could be considered feasible. Expenditures should be limited to grant funds already allocated until technology improves. Large industry groups or government research programs should finance further efforts, not Virginia ratepayers.

Solar PV Risks and Integration

Dominion has done a nice job in the IRP of discussing the challenges that distributed energy resources bring to the grid, especially the rapid variability of solar. The commission must create appropriate policies and rates to encourage Dominion to develop and maintain a robust and reliable grid. It is at the level of the distribution grid that the energy transformation will unfold. High voltage transmission and central station generation have evolved into a regional wholesale marketplace governed by federal oversight. State regulators, by creating the appropriate environment through leadership, policies and rates can determine customer value, the health of utilities, and the vitality of the state economy. A robust distribution grid with two-way energy and information flows and open access to customers, third-parties, and utility resources is essential.

Fair policies must be developed to properly recognize costs to avoid cross subsidies. But fair rates must also recognize the value that distributed generation brings to the system. Several utilities have wrestled with this issue and often have come up with different answers based on their priorities and system characteristics. Rocky Mountain Institute has created an unbiased methodology which could serve as a guideline for developing a more comprehensive Value of Solar Tariff, which fairly recognizes both the costs and benefits of customer distributed generation. Austin Energy has also completed an in-depth review of the costs and benefits of residential solar, while developing a new tariff that has been widely reviewed by other utilities. Policies must allow experimentation, and require the development of standards and open protocols to ensure interoperability and integration, while addressing cyber security. Utilities and regulators must also recognize that certain types of grid equipment and infrastructure can no longer be amortized over 20-30 years due to the shorter technology lifecycle.

Given open access and fair, consistent policies and cost signals, non-utility sources could make a significant contribution to system supply and load reduction. These contributions should be fully reflected in the Integrated Resource Planning process to present an accurate picture for effective decision making.

Levelized Busbar Costs

Cost comparisons of various types of generation are useful for planning purposes, but they do not always tell the whole story. Alternatives with similar costs might have markedly different probabilities that those costs are sustained throughout the operational life of the facility. Decision makers must consider risks, and the probability of those risks occurring in addition to costs when selecting the best options. Below is a table identifying various levels of risk associated with the primary methods of dealing with load requirements:

Risk Assessment of New Resources[20]

Resource	Initial Cost Risk	Fuel Cost Risk	New Regulations	Carbon Price	Capital Shock	Planning Risk
Efficiency	Low	None	Low	None	None	None
Gas CC	Medium	High	Medium	High	Medium	Medium
Nuclear	Very High	Medium	High	None	Very High	High
Solar PV distr.	Low	None	Low	None	Low	Low
Solar Utility	Low	None	Low	None	Medium	Low
Wind – onshore	Low	None	Low	None	Low	Low

The IRP references that 1000 MW of solar requires 8,000 acres of land. This is a misleading figure and is often used as a negative point when solar is compared with other alternatives. First, when land use is assigned to other options such as combined-cycle or nuclear plants, usually only the land occupied by buildings, substations and cooling towers is included (sometimes just the buildings). This is not accurate. Calculate the acreage within the exclusion zone for a nuclear plant. It is vast. If this land is not truly required for the safe operation of that facility, try getting approval to build something on it. Although empty, this land is definitely required for the nuclear facility. The same is true for the gas-fired plants to a lesser degree.

When building a utility scale solar facility on the property of an existing facility as Dominion is proposing for several installations – zero new land is used that is not already allocated to utility operations. A thousand megawatts of commercial and residential distributed solar could be built

[20] Practicing Risk-Aware Electricity Regulation, A Ceres Report, November 2014, https://www.ceres.org/resources/reports/practicing-risk-aware-electricity-regulation/view

without ever touching the ground. It is possible that an amount of solar generation could be built using less land than is required for an equal capacity combined-cycle unit.

Nuclear Extensions

The costs of pursuing an additional 20 year extension of the operating licenses for the existing nuclear plants may involve substantial costs. Very expensive components such as steam generators must often be replaced and various safety issues require new investment. Issues such as this kept the San Onofre nuclear plant in California from renewing its license. As mentioned previously, Dominion Resources chose to close its Kewaunee nuclear plant in Wisconsin because it could no longer be profitable in the MISO market. These choices are years away, but it should be recognized that this might not be a low cost option.

The costs for North Anna 3 are far too optimistic and bear no relation to what is actually being experienced with new nuclear projects, as previously discussed. Either, a realistic number should be supplied or this option should be eliminated. Using cost estimates from vendors is not a satisfactory solution. Real costs, such as from Watts Bar 2, or other plants partially under construction (but experiencing substantial delays and cost overruns) would provide more reasonable guidance as to possible future costs. Hanging on to the very unlikely possibility that cost-effective new nuclear capacity will be available late in the planning period will postpone serious evaluation of more likely scenarios.

Solar PV

When evaluating utility scale PV at greenfield sites, the requisite substation and transmission costs should be included in the cost of the solar project. Leaving these costs out of the solar project cost disproportionately favors utility scale projects over smaller, more distributed ones that do not require new transmission service. The benefits of distributed generation should also be a net reduction in the costs of those distributed units. Geographically dispersed utility or non-utility owned sites of .5 – 5 MW could reduce solar variability in the system and provide greater grid reliability and support, especially if paired with an appropriate amount of storage.

Extending the central station mindset to 21st century technologies such as solar has some benefit when developing existing power station sites and taking advantage of existing substations and transmission resources. However, it should not be overdone to treat all new solar additions as "just another power plant". Distributed generation has unique benefits that are difficult to realize with traditional methods of generation. Solar offers the flexibility to be used in both large utility scale arrays and smaller more distributed facilities. Fixed costs can be lower per unit of energy when spread out over larger installations. However, many advantages accrue for grid stability and reliability when generation resources can be optimally located in the system. These benefits should be factored into the cost comparisons of various solar alternatives. Incentives could also be used to encourage customer and third-party owned solar in areas where it best serves the grid.

Emerging and Renewable Energy Technology Development

Research and Development Initiatives – Virginia

The Solar Pathways Project appears to be a promising collaboration to develop a solar strategy for Virginia. The description indicates that it is to be a utility administered program. This should not mean that the scope of the project should limit solar development in Virginia to utility owned projects. The collaborators should investigate ways to encourage solar development by customers, third-parties and utilities in ways that benefit the entire state. Insights should be gained from other states that have been dealing with these issues longer than Virginia. New Jersey, New York, Vermont, Massachusetts, and North Carolina all could provide the benefit of their experience with solar policies. States in the West also have valuable experience to share but their conditions are a bit different from ours. The project participants should also contribute ideas about fair ways of handling the costs and benefits of distributed solar generation. Net metering rates and overall Value of Solar tariff issues should be broadly discussed. Community solar, solar/battery combinations, residential solar related to home energy networks and energy efficiency also should be considered. Innovative ideas about how to add distributed solar to public buildings such as government and school facilities should be gathered. Dominion can do substantial good for its system and the communities it serves with an open, supportive program for solar development.

Offshore Wind – Virginia

As previously mentioned, Dominion expenditures should be limited to the funds awarded by the DOE for the VOWTAP project. Technology and infrastructure must evolve for offshore wind to be a cost-effective opportunity. Iberdrola, the owner of two utilities in New York State, is a large Spanish energy company and wind turbine developer. They might be willing to share their experience or perform a demonstration project in the Great Lakes to help further offshore wind development in Virginia.

Electric Vehicle (EV) Initiatives

Adoption of electric vehicles is increasing in Virginia. Off peak charging programs are useful to investigate. Some utilities are exploring programs which view EV's as an asset to the grid rather than a liability to be managed. These programs typically involve using EV batteries as a grid resource during peak periods. This makes charging and capacity sharing more complex but it can be done so that is beneficial both to the utility and to the EV owners. We should be looking for more ways for the evolving grid to facilitate many more innovative applications. Dominion might consider a demonstration project supporting more electric vehicle use such as electric transit buses and various car sharing and last-mile innovations to use electricity to promote better community transportation solutions. The SCC should support low-cost exploratory programs to extend the benefit of electricity to reduce costs and environmental impacts of transportation in communities around the state. Consider investigating Rocky Mountain Institute's "Project Get Ready" program, which is working to prepare for the electrification of the transportation system.

Future DSM Initiatives

Energy efficiency, peak load shifting and other demand side management programs (DSM) are the most cost effective methods of providing additional capacity (by reducing loads). Nationwide averages for energy efficiency measures are about $.025 - $.03 /kWh, well below the prices of other generation alternatives, even wind (in Virginia). Typical returns are 2-8 times every dollar invested; with complete paybacks usually occurring within a few years.

Dominion Virginia Power's DSM programs follow the typical range of utility DSM programs, although the transactional pricing project looks particularly interesting. Lessons learned from transactional pricing in the PJM wholesale markets might have some application to the retail market as the necessary metering, two-way communications, rate structures and other components become readily available.

As useful as these programs are, Dominion's success with them does not compare well with their peers. A ranking of the 32 largest investor owned utilities was performed by Ceres, a non-profit organization that directs a network of over 110 institutional investors with collective assets totaling more than $13 trillion.[21] Cumulative annual energy savings and incremental annual energy efficiency savings were compared for all 32 utilities. Results were expressed as a percentage of annual retail sales (for 2012) to allow for comparison across utilities of different sizes. Dominion was the 12th largest of the 32 utilities evaluated. For cumulative annual energy efficiency, Dominion ranked 31st of 32 with 0.41%. The results for the utility ranked highest in this category, was 17.18%. For incremental annual energy efficiency, Dominion was at the bottom of the list of all companies surveyed, 32nd out of 32 - at 0.03% per year. The highest in this category was 1.77% /yr. It is clear that Dominion has not yet demonstrated the leadership in DSM programs of which they are capable.

Just as the modernized distribution grid is the cornerstone of the 21st century energy transformation; energy efficiency is the means that will reduce the costs. When the load is less, everything gets cheaper: fewer rate riders for new generating capacity, less transmission and distribution expense, and lower energy costs because the peak is lower. Plus the even lower bills for those who have reduced their individual energy use. Rocky Mountain Institute has produced a well researched energy and efficiency plan that will support an economy 158% bigger by 2050

[21] Benchmarking Utility Clean Energy Deployment:2014, Ceres, Inc., July 2014, http://www.ceres.org/resources/reports/benchmarking-utility-clean-energy-deployment-2014

that requires no coal, no oil, no new laws, no new federal taxes, no subsidies, or even any new inventions. This can be done at a price that is $5 trillion less (nationwide) than our current business-as-usual approach with no consideration of the hidden costs of fossil fuels or a price for CO_2.[22]

Some might view this plan as overly optimistic, but it points the way as to what might be possible. Mr. Lovins's original predictions for the future of our energy system published in the late 70's (Soft Energy Paths) proved highly prophetic; although they greatly diverged from utility predictions at the time they were published. Rocky Mountain Institute (RMI) partnered with Johnson Controls and others to do an energy efficiency retrofit of the 2.7 million square foot Empire State Building. The project reduced the building's energy use by 38%, saving $4.4 million annually, while creating 252 jobs.[23] Who would have thought retrofitting the 6,514 operable windows of the Empire State building for energy efficiency would be time- or cost-effective? But it was. Many other innovative ideas contributed to the total savings.

RMI also led the retrofit of a twelve-story office building in Rosslyn, Virginia. Through a combination of energy efficiency strategies, including replacing the HVAC and lighting systems and providing tenant education, the building energy use was reduced by 35% in just one year. This resulted in annual savings of $250,000 on energy bills and eliminated more 1,200 metric tons of CO_2. (Energy efficiency is the lowest cost method of obtaining CPP credit).[24] The primary objective of the client was to modify a mid-class building that was already 100% leased and elevate it to the top of the market by increasing efficiency, sustainability and comfort.[25]

Imagine a concerted effort in Virginia to retrofit our state and local government buildings and schools. This would provide savings to Virginia residents both as ratepayers and as taxpayers. Improving the energy efficiency of existing commercial buildings is one of our greatest opportunities. If our existing buildings in the U.S. were a nation, its energy consumption would rank third after China and the U.S. More than a trillion dollars is currently flowing out of our buildings in the form of wasted energy.

In 2007 American Electric Power (AEP), the parent company of Appalachian Power, launched gridSMART, a Smart Grid initiative designed to deliver a number of customer and grid efficiency benefits. The gridSMART program is growing into a comprehensive demonstration

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[22] Reinventing Fire: Bold Business Solutions for the New Energy Era, Amory B. Lovins, Rocky Mountain Institute, Chelsea Green Publishing Company, White River Junction VT, 2011

[23] Empire State Building Retrofit Surpasses Energy Savings Expectations, May 31 2012, http://blog.rmi.org/blog_empire_state_retrofit_surpasses_energy_savings_expectations

[24] "Energy Efficiency as a Low-Cost Resource for Achieving Carbon Emissions Reductions", National Action Plan on Energy Efficiency, September 2009.

[25] Deep Energy Savings in Existing Buildings, New Buildings Institute Case Study, http://www.rmi.org/Content/Files/1525_Wilson_Blvd_true_stories.pdf

program involving 110,000 customers in central Ohio. The demonstration will include smart meters, distribution automation equipment to better manage the grid, community energy storage devices, smart appliances and home energy management systems, a new cyber security center, PHEVs, and installation of utility-activated control technologies that will reduce demand and energy consumption without requiring customers to take action. Perhaps AEP could offer some guidance about how that program might be adapted to Virginia.

It is unrealistic to assume this can all be accomplished by Dominion. It is difficult for a utility to aggressively pursue a strategy that lowers its revenues. As long as we continue solely to rely on the "cost of service" and volumetric (price per kWh) model of paying our utilities, they will suffer financially from doing what is best for the customer. We must also pay them for the value they provide so they have an incentive to create a modernized grid and support energy efficiency programs either of their own or those provided by energy service companies (ESCO's) or other organizations. Decoupling rates does not by itself provide utilities enough financial incentive to aggressively pursue energy efficiency. Usually a reward for high performance works best.

Vermont has recognized the inherent conflict in asking the utility to maximize the opportunities for load reduction. In 1999, Vermont set up an independent energy efficiency utility, which later became Efficiency Vermont (operated by a non-profit organization). Since that time, Vermont has been recognized as one of the leaders in energy efficiency in the U.S. This could be one of many options considered to take advantage of the benefits of substantially increasing our energy efficiency. An aggressive program would lower energy costs, provide many new jobs, attract innovative new businesses and skilled employees, and vitalize Virginia's economy. Coupled with appropriate regulatory policies it would also keep our utilities healthy and prepared for the modern energy era.

Other states are well on their way to taking leadership in this arena. Vermont and California have been consistent leaders. Ohio and Indiana have adopted standards of 2% per year annual energy savings by 2019. Massachusetts has committed to making energy efficiency its "first fuel" asking utilities to invest $2.2 billion in order to save customers $6 billion in energy costs. Their plan calls for 30% of Massachusetts' energy to be provided by energy efficiency by 2020.[26]

Analysis by Navigant Consulting indicates that programs that achieve the highest energy savings do so at the lowest cost (less than 2 cents per kWh saved); indicating that energy efficiency becomes less expensive with greater investment.

Because efficiency is the lowest-cost resource, successful projects lower everyone's electricity bills. The Northwest Power and Conservation Council, whose effective efficiency programs

[26] "The 21st Century Electric Utility: Positioning for a Low-Carbon Future, July 2010, Ceres, Inc.

saved customers approximately $1.8 billion annually in 2008, showed that while efficiency programs might slightly increase rates – customer bills will decline.[27]

When independent organizations perform the energy savings projects, on-bill repayment to those independent organizations can lower financing costs and simplify things for both customers and vendors. This is usually a minimal additional cost for utilities, but they should be paid for their efforts.

With aggressive energy efficiency and demand management programs, whether accomplished by the utility, the customer or other organizations, Dominion should see a much more substantial deviation with DSM from the load curves shown for 2020 and 2030. Consider Massachusetts' goal of 30% energy efficiency reductions in load by 2020. With the proper policies and the will to accomplish them, such a reduction is possible in Virginia.

Chapter 6 – Development of the Integrated Resource Plan

IRP Process

The IRP process as described is a tried and true approach, using well accepted, industry standard modeling software and accomplished by skilled utility personnel. The concern is that it is a tried and true approach, differing little from what has been done for the past several decades. It is not so much the methodology, but the assumptions that should be challenged. The industry has seen many changes: load growth dips in response to economic declines; EPA regulations cause a move away from coal to nuclear; then a move away from nuclear and back to coal because of costs, demand decline and safety issues; first a prohibition of natural gas, then a nationwide move back to natural gas to replace coal. All of these have been evolutionary changes. Regulators often needed to prompt utilities to respond more quickly to the changes, but through the second half of the 20th century the electrical utility industry fulfilled its promise of keeping the lights on (except for a few major blackouts). As a long term trend, demand continued to grow, allowing utilities to be paid for what they built and providing a steady return to investors.

In the new millennium the pattern began to change. We discovered that our economy could grow without an increase in the use of electricity. New technologies came on the scene that gave customers choices about reducing their loads or generating their own electricity. Utilities are accustomed to calling the shots, building large central station power plants and increasing their profits by building more plants and power lines. Regulators are challenged to avoid raising rates to cover growing utility expenses because the load is not growing as before. Often rate riders and special surcharges are added so that it appears that the "base" rates have not changed. But customers see their bills rise nonetheless.

[27] "Energy Efficiency's Role in Limiting RGGI Leakage", Bill Prindle, ACEEE, www.rggi.org/docs/prindle.ppt

The tide is turning. The electricity industry is shifting to be centered on the customer, just as unregulated businesses are. Utilities are being asked to provide the services that customers want rather than deciding what the customers can have. Some states are embracing this change, while others are dragging their feet. The changes are coming despite the desires of the utilities or the regulators. The long term vitality of the state economy is dependent on the response. States that encourage the development of a 21st century energy economy will attract new businesses, more skilled workers and create more vibrant communities and healthier utilities. Those that don't will devolve to second tier status.

It is very difficult for organizations that have succeeded by doing things a certain way to alter their habits to meet changing conditions. The Integrated Resource Planning process is one of the key ways that we can discuss an alternative future and how best to respond to it.

The SCC should request a variety of modeling runs that include scenarios beyond the narrow band of "business-as-usual". Section 6.6 describes an effective methodology of assessing risks, however it appears the deviations from the standard assumptions were kept within fairly narrow bounds. The utility staff probably feels challenged enough having to deal with CPP regulations and the integration of new technologies and distributed generation. However, we are just at the beginning of a major transition in our energy system. This IRP is an extension of past experience. It assumes moderate load growth; assumes that Dominion will be the primary provider of new solar and storage facilities; expects that most energy savings will come from utility DSM programs; and that natural gas, the fuel on which Dominion will become increasingly dependent, will rise in cost at a moderate and predictable rate.

These assumptions are not foolhardy. They are based on recent patterns. However, few if any of these forecasts are likely to play out over the next 15 years in the manner predicted. It is not the planner's fault. It is difficult to foresee the outcome of transformational change. However, the SCC is being asked to approve plans that have long term consequences. The utility's habit of adding capacity in large chunks makes it difficult to rapidly respond to significant variations in load growth. Once approval is given to build a new facility, even if load substantially declines, the utility expects to be paid for its investment even if customers don't need it to the degree expected.

Given the responsibility of the SCC to protect the interests of the utility and the ratepayers, the Commission should order additional modeling runs to identify the effects of substantial changes in the different scenarios. What if the expected load in 2020 is offset by 30% using energy efficiency as Massachusetts is proposing? What if customers install 200, 500, or 800 MW of distributed solar between now and 2020 (the cost of solar is expected to be half of today's prices by 2020). What if natural gas prices double by 2025, triple by 2030? What if a major loan default by oil and gas developers prompts another economic decline similar to or greater than 2008? Many would consider these events as outliers, but there is a measurable chance that any one of them could occur. What if some occurred in combination? Risks should be assessed even if the probabilities are considered low. The consequences are too great for the SCC to assume that things will continue as we expect for the next 15 years. Entering a time of greater uncertainty, we should design our energy system to be flexible and rapidly responsive to unforeseen events. The system that we have designed to date does not possess those characteristics. It was not required. We designed for stability and predictability. But times are changing.

Chapter 7 – Short-Term Action Plan

The Dominion IRP notes that, "A combination of developments on the market, technological, and regulatory fronts over the next five years will likely shape the future of the Company and the utility industry for decades to come". It is exactly this notion that has shaped the comments presented in this document. We must seize this chance to reshape our vision of Virginia's energy future. With the normal bi-annual reviews and rate-making proceedings held in abeyance during this period, there is a unique opportunity to examine the best ways to reliably serve Virginia's energy needs in the 21st century. With appropriate policies a robust, reliable distribution grid can be developed which supports two-way flows of energy and information. This will create a platform for innovation for utilities, third-parties and customers to lower costs, while increasing the flexibility and reliability of our electrical system. With funds declining for the many federal facilities in Virginia, it is important that we use this opportunity to advance our energy system to create an inviting climate for innovative businesses and their skilled employees. Neighboring states are already aggressively working to establish themselves as the innovative energy center of the Southeast. Virginia cannot afford to be left behind.

A renewed energy vision for Virginia should include consideration of the following principles:

1. **Saving energy is cheaper than creating it; and releases no harmful emissions.**

Reducing load through energy efficiency, thus freeing up existing capacity, is cheaper than building new generating capacity. Effective energy efficiency measures cost 2-3 cents per kilowatt-hour; far less than any of the options considered in this IRP for new generating capacity. Tunneling through the cost barrier by investing more in energy efficiency has been shown to be more productive than just spending a little on efficiency measures.

Well conceived retrofits of commercial buildings often reduce annual energy use by 30-40% and provide immediate savings to building owners. Customers, energy service companies (ESCO's) and other organizations should be encouraged to make these investments. These energy savings benefit all ratepayers. When the load is reduced, costs decline for everyone. Lowering the peak reduces the need for expensive peaking units. Adding new generating units results in new rate riders to cover the utility's costs and provide a return to investors. Reducing the load avoids or postpones those added expenses. Transmission and distribution expenses increase with higher system loads. Keeping the load lower reduces those expenses as well.

It is difficult to ask utilities to fund and promote efforts to lower their revenues. Vermont created an efficiency utility in 1999 which is now operated by a non-profit. They are fully engaged in promoting cost-effective energy efficiency projects. Virginia could consider an organization such as this, which would benefit residents and the state economy without asking ratepayers or utility investors to fund it. It could be established and operated without costing taxpayers money. The utilities could provide on-bill repayment services for these projects. Having utilities collect the monthly charge to pay for the retrofit project would lower the cost of financing and ease the payment process for customers and vendors. Customer bills would still be lower, including the project repayment. Then lower yet when the project cost has been fully repaid. Utilities should be compensated for this payment collection service.

The efficiency utility could also assist in improving the energy efficiency of substandard buildings. Such dwellings contribute disproportionately to the peak. This would benefit all ratepayers, but especially low-income residents. As Virginians we can find creative ways of benefiting our fellow citizens.

Significant savings are available given the proper approach and sufficient will to see it through. Massachusetts adopted a statewide energy plan that calls for 30% of the load in 2020 to be provided by energy efficiency. Many other states are developing plans to utilize the many benefits of energy efficiency.

New policies would be required to keep utilities financially healthy as their load declines. They must be paid for the value that they provide. Utilities would be best suited to promote demand reduction programs that would move energy use away from the peak. This reduces the peak (and high costs for operating peaking units), but keeps energy use about the same. Innovations for providing remote utility control over home heating and cooling systems and water heaters are being developed which could greatly assist reducing loads during peaks. Studies in New York indicate that flattening usage in the 100 hours of the greatest peak demand would save over $1.2 billion annually.

2. Energy is becoming customer centric.

Advances in technology, communications and digital controls now allow customers to take greater control over their energy use; including how and where it is generated. Utilities are at the center of this transformation. A resilient grid that provides two-way flows of energy and information is essential for providing a multitude of customer choices. Utilities should have incentives (which are best if performance based) to provide these necessary services.

The central station, one-way flow of energy and information from utility to customer is giving way to a varied network of customer, third-party and utility resources. The utility distribution grid must provide standards for interconnection and interoperability to ensure reliable operation.

Plans for the development of the electrical system such as the Integrated Resource Plan, must include changes in load and generating capacity coming from customers and third-parties. They will contribute a greater share of these changes as time goes on. For the SCC to make proper determinations about utility plans they must consider the entire picture, not just the utility portion.

3. **Utilities are essential to building and operating the distribution platform.**

The distribution platform is the enabling technology for the transformation of our energy system. Utilities must build the necessary infrastructure to support this new dynamic system. The information age has arrived in the energy sector and customers have a role to play. The grid must transmit information about system conditions and successfully integrate the distributed energy resources (DER's) that can affect demand and supply throughout the grid. All DER's must be considered "resources" whether owned by the utility, customers or third-parties. Ideally, the distributed resources that are changing the grid can also be used to optimize the grid. The modernized grid must reliably integrate and control distributed generation and storage, and provide services such as reactive power and voltage control. Information must flow to customers in ways that allow them to manage home energy networks, smart thermostats, demand response and whatever else is required to permit them to control their energy use. All energy and information flows should be accomplished in a secure manner.

In this time of transition, regulators and utilities need to see opportunities rather than believing they need to deal with threats. If utilities perceive that the interests of their customers are in conflict with the interests of their shareholders, there will be a major problem. We are just scratching the surface. The possibilities for innovation are immense.

4. **Energy efficiency and renewable generation are the lowest cost methods of meeting the Clean Power Plan (CPP) requirements.**

Load reductions from energy efficiency and renewable generation (primarily solar) provided by customers, third-parties and utilities are by far the cheapest methods to reduce CO_2 emissions. New nuclear capacity is not a cost-effective choice or one whose in-service date can be relied on for providing new carbon-free capacity.

5. **Generation choices which do not require fuel (solar, wind) have lower risks of rising prices than those that require fuel.**

This seems obvious, but is not always given much value. Once a solar panel is installed, the cost of energy is fixed within the bounds of annual solar variation. And can be precisely fixed with a Power Purchase Agreement. Units which rely on natural gas are at the mercy of the market. Dominion can arrange a contract for firm supply, which guarantees a supply but not a price. This protects against price extremes during supply shortages, but prices still rise. Several independent experts have projected that the supply of affordable ($4 mcf) natural gas will begin to decline from shale gas fields beginning in 2020, due to the increased requirements to supply power plants and LNG exports which are new demands for the natural gas supply chain. In addition to the expected scenarios, planning discussions should evaluate scenarios which assess the fuel cost surcharges to ratepayers if gas prices double or triple.

6. **The future is uncertain. We should design our electricity system to be flexible and rapidly responsive to demand, economic upsets, fuel prices and technology changes.**

For decades utilities built ever larger central station power plants and customer rates declined. Today, building new large facilities increases rates. Adding large amounts of generation at one time makes it harder to mirror gradual changes in load growth. Shortfalls or surpluses in generation can be balanced by purchases from or sales to the wholesale market (PJM). However, large capital intensive projects increase the risk to the utility that they might not fully recover their cost. The short lead time and small increments of change for efficiency and solar lend much greater flexibility and responsiveness to meet unanticipated events.

Other issues such as transactive pricing, ways of protecting utility finances when load declines, rewarding them for building and operating a modernized distribution grid, are topics more appropriate to rate proceedings rather than this docket.

With the rate case hiatus, there is a grand opportunity to examine how best to meet new environmental regulations while creating a dynamic energy system that provides clean, affordable energy and energy saving options. By interconnecting producers and consumers with diverse supply resources, the electricity grid reduces risk, enables greater economic efficiency, and lowers costs for all. The historical role of the utility to coordinate operations and planning does not fade away but rather grows in importance as distributed resources proliferate. The desire is to retain many of the benefits of the current system while at the same time improving it to provide a platform for innovation around products and services that offer greater customer convenience, control and participation. Sometimes it takes only a shift in perspective. For over a century the utility industry perceived its role as creating new supply to meet demand. Perhaps it is time to consider adjusting demand to meet supply.

Respectfully submitted October 12, 2015 by:

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To: Hon. Joel H. Peck, Clerk
State Corporation Commission
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1300 East Main Street
Richmond, Virginia 23219

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STATE CORPORATION COMMISSION

151030117

From: Dominion Large Energy Buyers[1]

RE: Virginia Electric and Power Company's Integrated Resource Plan filing pursuant to Va. Code § 56-597 et seq. Case No. PUE-2015-00035

Dear Mr. Peck:

As employers in Virginia and large electricity consumers of Dominion Virginia Power, the undersigned companies write to express our support for increased and diversified renewable energy supply in Virginia as part of Dominion Virginia Power's 2015 Integrated Resource Plan (IRP) submission.

As global companies providing products and services to consumers around the world from our operations in Virginia, we value not only a reliable and affordable electricity supply but also a clean one. For example, many of the undersigned companies have signed the *Corporate Renewable Energy Buyers Principles* (see attachment) because the Principles describe our common needs as large renewable energy buyers and are helping us fulfill our public goals to reduce global warming emissions and source renewable energy. Our ability to access power from renewable resources is essential to our corporate energy strategies.

States that have expanded their production of renewable energy have reaped benefits including diversifying the energy supply, tapping fixed-price and often least-cost energy sources, improving air quality, attracting and maintaining business in the state and developing a local renewable energy industry with the potential to contribute billions of dollars of in-state economic growth and thousands of jobs. Dominion states in its IRP submission that solar is the least cost option to comply with EPA's Clean Power Plan. This creates an opportunity to expand fixed-price, zero emissions renewable energy as a benefit to all Dominion rate-payers today and begin an orderly transition to a low-carbon future.

In its submission, Dominion recognizes that changing customer needs will influence its final decisions on resource procurement. As some of Dominion's largest electricity consumers in the state, we support increasing the supply of renewable energy on the grid in Virginia. We also have specific goals for our own operations and leased facilities and we are looking for opportunities to cost-effectively procure greater quantities of renewable energy from the grid than is currently available.

Our goals seeking access to renewable energy are increasingly important to our decisions about where to site new facilities, particularly within the state's growing information and communications technology (ICT) industry. Represented by *Future of Internet Power*, influential ICT companies are seeking to power the internet with 100 percent renewable energy. *Future of Internet Power*'s member companies have a keen interest in Dominion's power plans as Virginia is home to many large scale, energy intensive data centers that these companies operate or lease now or are considering for future use. Given the growing

[1] The Dominion Large Energy Buyers are iconic companies that have signed the Corporate Renewable Energy Buyers' Principles and/or belong to the Future of Internet Power working group.

movement of ICT companies and data center service providers toward public commitments to use 100 percent renewable energy, we strongly encourage Dominion to maximize the use of renewable options.

The undersigned companies are operating and growing our businesses in Virginia. We support Dominion's goal to provide its customers with affordable, reliable, and clean energy, and we believe this is possible with smart resource planning that maintains Virginia's profile as a state of choice. We invite Dominion and other stakeholders to engage with us on collaborative opportunities to meet mutual objectives to increase the supply of renewable energy in Virginia.

Signed,

Adobe Systems Inc. | Autodesk, Inc. | Equinix, Inc. | Facebook, Inc.
Hilton Worldwide | Intuit Inc. | Kaiser Permanente | LinkedIn Corporation
Microsoft Corporation | Symantec Corporation | Wal-Mart Stores, Inc.

CC: Edward Baine, Senior Vice President of Transmission and Customer Service, Dominion

Addendum:

Links to referenced initiatives:

Corporate Renewable Energy Buyers Principles: www.buyersprinciples.org

Future of Internet Power: http://www.bsr.org/en/collaboration/groups/future-of-internet-power

Attachment:

Corporate Renewable Energy Buyers Principles

CORPORATE RENEWABLE ENERGY BUYERS' PRINCIPLES: INCREASING ACCESS TO RENEWABLE ENERGY

Bloomberg | BD | Sprint | ebay inc | VOLVO

CISCO | f | ARUP | hp | ADITYA BIRLA NOVELIS | P&G

novo nordisk | Adobe | DIGITAL REALTY | STAPLES | Walmart

MARS | REI | Johnson & Johnson | IKEA | YAHOO!

KAISER PERMANENTE | Unilever | AUTODESK | io | GM | TARGET

3M | EMC² | workday. | intel | Genentech A Member of the Roche Group

starwood Hotels and Resorts | amazon | salesforce | DU PONT | HILTON WORLDWIDE

INTUIT | EQUINIX | Sealed Air Re-imagine | Etsy | Microsoft

Sixty percent of the largest US businesses have set public climate and energy goals to increase their use of renewable energy.[1] Companies are setting these goals because reducing energy use and using renewable energy have become core elements of business and sustainability strategies.

Businesses are actively and successfully adding renewable energy to their own facilities and increasingly entering into contracts to buy or invest in offsite renewable energy. Even though cost-effective project opportunities currently exist, with billions of kilowatt hours still needed to meet their renewable energy goals, businesses face a variety of challenges accessing cost-effective projects on favorable terms.

The following principles frame the challenges we are facing and our common needs as large renewable energy buyers. We developed these principles to help facilitate progress on these challenges and to add our perspective to discussions underway across the country on the future of our energy and electricity system.

We hope these principles will open up new opportunities, choices and collaborations that will help businesses meet their public goals to increase the use of renewable energy.[2] We encourage others to join us in supporting these principles to expand and streamline the opportunities for renewable energy procurement.

IN ORDER TO MEET CUSTOMER NEEDS AND DRIVE IMPACT WE, THE ABOVE-SIGNED COMPANIES, ARE SEEKING, IN NO PARTICULAR ORDER, THE FOLLOWING FROM THE MARKETPLACE:

1 Greater choice in our options to procure renewable energy

It is important to have choice when selecting energy suppliers and products to meet our business and public goals.

2 Cost competitiveness between traditional and renewable energy rates

We know renewable energy can already achieve cost parity, or better, compared with traditional energy rates. When purchasing renewable energy directly, we would like to be able to buy renewable energy that accurately reflects the comprehensive costs and benefits to the system. Many of us are willing to explore alternative contract arrangements (e.g., entering into long term supply arrangements with utilities and other suppliers to provide revenue certainty) that can bring down the cost of capital.

3 Access to longer-term, fixed-price renewable energy

A significant part of the value to us from renewable energy is the ability to lock in energy price certainty and avoid fuel price volatility. Many companies would like to have options for entering into contracts over various time periods.

FOOTNOTES

1 WWF, Ceres and Calvert Investments (2012) Power Forward: Why the World's Largest Companies are Investing in Renewable Energy.

2 These are general principles and they are not intended to limit the scope of individual company efforts to responsibly procure renewable energy.

4 Access to projects that are new or help drive new projects in order to reduce energy emissions beyond business as usual

We would like our efforts to result in new renewable power generation. Pursuant to our desire to promote new projects, ensure our purchases add new capacity to the system, and that we buy the most cost-competitive renewable energy products, we seek the following:

a. Access to bundled renewable energy products—energy and Renewable Energy Credits (RECs)

We are increasingly interested in access to bundled energy and REC products. Unbundled RECs do not deliver the same value and impact as directly procured renewable energy from a specific project or facility.

b. Ability to prevent double counting within the energy consumer community

In order to claim the benefits of our renewable energy purchases to satisfy our public goals and reduce our carbon footprint, current US rules require that we retain ownership of the RECs or that they are retired on our behalf.

Some companies find this single-instrument system creates competition between energy generators and energy users that can slow the growth of voluntary corporate renewable purchases. We welcome discussion to explore market mechanisms that enable greater voluntary growth of renewable energy while maintaining accounting integrity.

What is most critical to us is that we have the ability to add more renewable energy to the system and claim the consumption of the relevant renewable energy and GHG emission benefits while preventing another energy user from claiming consumption of the same renewable energy.

c. Renewable energy delivery from sources that are within reasonable proximity to our facilities

Where possible, we would like to procure renewable energy from projects near our operations and/or on the regional energy grids that supply our facilities so our efforts benefit local economies and communities as well as enhance the resilience and security of the local grid.

5 Increased access to third-party financing vehicles as well as standardized and simplified processes, contracts and financing for renewable energy projects

To access renewable energy at the competitive prices and scale we need to meet our goals, many companies are financing and/or procuring renewable energy through third-party providers using power purchase agreements (PPAs) and/or lease arrangements. Increasing access to these types of effective and affordable financing tools is critical.

Initially, for some companies, these processes can be complex and costly since they are outside of their core business functions. Simplifying and standardizing policies, permitting, incentives and other processes for direct procurement are high priorities for many companies.

6 Opportunities to work with utilities and regulators to expand our choices for buying renewable energy

Procuring renewable energy in partnership with our local utilities may be a more efficient and cost-effective option. We welcome the opportunity to work with local utilities to design and develop innovative programs and products that meet our needs as well as those of our energy suppliers. In such collaborations, we would seek renewable energy products and programs that address the above principles and that

a. fairly share the costs and benefits of renewable energy procurement

We seek to purchase renewable energy that reflects the net costs and benefits to the system, including the actual cost of procurement and benefits, such as, but not limited to, avoided energy and capacity benefits, without impacting other rate payers.

b. apply to new and existing load

To meet our public goals, we need renewable energy for both new and existing operations.

CORPORATE RENEWABLE ENERGY BUYERS' PRINCIPLES: INCREASING ACCESS TO RENEWABLE ENERGY

These principles have emerged through discussions between the participating companies convened by WWF and WRI. The companies identified common challenges to meeting their renewable energy goals and proposed establishing these principles. They worked together, facilitated by their NGO partners, with the goal of clearly communicating to the market the renewable energy products they would like to buy.

For more information or if your organization is interested in joining the principles, please visit **www.buyersprinciples.org** or contact:
Bryn Baker – bryn.baker@wwfus.org
Priya Barua – pbarua@wri.org

WWF

WWF is an organization dedicated to stopping the degradation of the planet's natural environment and building future in which humans live in harmony with nature. WWF achieves this mission through innovative partnerships that combine on-the-ground conversation, high-level policy and advocacy and work to make business and industry more sustainable. This work includes engagements with hundreds of companies across a range of sustainability issues, including our Climate Savers program and facilitation of the Corporate Renewable Energy Buyers' Group, which produced these principles.

WORLD RESOURCES INSTITUTE

The **World Resources Institute (WRI)** is a global research organization that spans more than 50 countries, with offices in the United States, China, India, Brazil, Europe, and Indonesia. Our 450 experts work closely with leaders to turn **big ideas into action** to sustain a healthy environment—the foundation of economic opportunity and human well-being. We focus on six urgent global challenges: food, forests, water, climate, energy and cities & transport.